Profiles in Renewable Energy: Case Studies of Successful Utility-Sector Projects

---

The Shape of Renewable Energy Technologies Today

As considerations of fuel diversity, environmental concerns, and market uncertainties are increasingly factored into electric utility resource planning, renewable energy technologies are beginning to find their place in the utility resource portfolio. This document profiles 10 renewable energy projects, utilizing six different renewable resources, that were built in the United States throughout the 1980s. For each project, the factors that were key to its success and the development issues that it faced are discussed, as are the project's cost, performance, and environmental impacts and benefits.

Renewable energy technologies have important advantages to utilities: they use a fuel source that is either free (such as sun or wind) or relatively inexpensive (such as wood waste or municipal solid waste); their project construction lead times can be significantly shorter than those of traditional power plants, thus reducing utility risks; their capacity can be increased incrementally to better match load growth; and they are environmentally cleaner than fossil fuels. Because of these advantages, many utilities and regulatory bodies are increasingly interested in acquiring hands-on experience with renewable energy technologies in order to plan effectively for the future. Furthermore, many financial incentives now encourage the manufacture and development of renewable energy technologies, including federal incentives contained in the Energy Policy Act of 1992.

A great deal of renewable energy development occurred in the 1980s, and the prime stimulus for it was the passage in 1978 of the Public Utility Regulatory Policies Act (PURPA), which created a class of non-utility power generators known as "qualifying facilities" or QFs. QFs were defined to include cogeneration systems and small power generators utilizing waste fuels and renewable energy sources. For the first time, PURPA required electric utilities to interconnect with QFs and establish contracts to purchase QFs' power output at "avoided cost," or the cost that the utility would have incurred by supplying the power itself. PURPA also exempted QFs from certain federal and state utility regulations.

Utility power purchase contracts, which many projects received under the requirements of PURPA, were the most important contributors to the success of the non-utility projects profiled in this document. By providing a predictable revenue stream, power purchase contracts significantly reduced the financial community's perceived risk of non-utility projects.

Other factors for success were transmission access and availability; federal and state tax incentives; special financing opportunities, such as federal loans; and the ability to satisfy other societal needs, such as the disposal of wood waste or municipal solid waste. In many cases, a cooperative effort among all affected parties was a dominant factor in project success.

In contrast to QFs, electric utilities played a relatively small role in the development of non-hydro renewables during the 1980s, in part because the government policies that drove much of the QF development during this period largely excluded utility developers. Utilities developed projects only where economics were highly favorable or as a component of their research and development (R&D) programs. For these utility developers, the regulatory treatment of project costs was an important concern. Although some utilities undertook renewable energy R&D projects without seeking cost recovery, cost recovery issues must be addressed if utilities are to invest more broadly in renewables in the future.

Overall, many regulatory, environmental, and economic factors spurred the projects profiled in this document, but a number of factors hindered the projects. These hindrances included negotiation of right-of-way for new transmission lines; mitigation of wildlife and protected lands issues; an overly long project-approval process; and technological issues, particularly for first-of-a-kind project endeavors.

Utility decision makers and regulators need to be aware that there are a number of successful renewable energy projects now in operation. By drawing on the experience of the projects profiled in this document, decision makers should be better equipped to evaluate the conditions under which specific renewable energy projects and proposals can be successfully implemented in the future.

Biomass

Biomass energy, one of the oldest energy sources known to man, uses the energy embodied in organic matter (mainly plants). Biomass-based energy systems utilize wood, agricultural and wood waste, municipal waste, and landfill gas as fuels. Biomass, in all its energy uses, currently supplies more than 3% of total U.S. energy needs and provides almost 10,000 MW of electric generating capacity. Wood fuels provide the bulk of this generation (66%), followed by municipal waste (24%), agricultural waste (5%), and landfill gas (5%). While biomass resources, in one form or another, are present in all 50 states, the development of short-rotation woody crops may significantly expand the future supply of biomass resources.

Wood is the leading biomass energy resource used for power generation, primarily because of its use as a boiler fuel in the lumber and pulp and paper industries. The lumber industry satisfies close to 75% of its energy needs through direct wood combustion, while the pulp and paper industry has achieved a 55% aggregate fuel contribution from wood. Many of these companies use cogeneration systems for power generation. The Edison Electric Institute estimates that more than 6000 MW of non-utility, wood-fired generating capacity was in place at the end of 1991.

Wood has environmental advantages in terms of emissions of carbon dioxide, a greenhouse gas. Although the burning of a tree releases carbon dioxide, an equal amount of carbon dioxide is removed from the atmosphere when the tree grows. Thus, so long as the trees that are burned are replaced by growing new trees, the net emission of carbon dioxide is zero.

Municipal waste is the second largest source of biomass power, generating more than 2000 MW of electricity and providing steam for industrial uses. More than 526,060 metric tons (580,000 tons) of municipal waste are generated in the United States each day, with three-quarters or more of this total going to landfills. With landfills nearing capacity, charging higher costs, and adopting stricter regulations, many localities have turned to waste-to-energy (WTE) systems as a disposal alternative-- an estimated 15%-20% of municipal waste is burned for energy. Several industry sources have predicted that from one-third to one-half of the nation's municipal waste could be burned for energy by 2000.

Agricultural waste plants are the third largest biomass generators, producing another 575 MW nationwide. These plants use such diverse feedstocks as bagasse (sugarcane residue), rice hulls, rice straw, nut shells, crop residues, and prunings from orchards and vineyards.

Finally, more than 100 power plants in 31 states burn landfill-generated methane. The high natural gas prices of the 1970s prompted the exploitation of methane, and its development was further spurred by the enactment of PURPA and federal tax incentives for the production of non-conventional fuels. Environmental concerns have also had a positive impact on the landfill methane industry. More than 10% of the nation's 6000 existing landfills are expected to require methane collection systems to comply with federal regulations on hazardous emissions from landfills. Methane is also a potent greenhouse gas, and this may provide greater impetus for landfill methane projects in the future.

Wood-Burning Plant Reduces Air Pollution

Kettle Falls Wood-Fired Plant
Washington Water Power Company

The Kettle Falls wood-burning plant overcame high initial costs to generate cost-effective power using local labor and fuel, while producing environmental benefits for the surrounding community.

During the late 1970s, the Washington Water Power Company (WWP), an investor-owned utility serving customers in eastern Washington and northern Idaho, began investigating alternative generation sources to expand its electricity supply base. The abundance of wood waste from the lumber industry contributed to the decision to build a power plant fueled entirely by that renewable fuel.

At the time, wood waste created by the numerous lumber mills in the area was being incinerated in wigwam burners primarily as a method of waste disposal. These burners had no pollution controls and thus posed a serious air pollution problem. A dedicated wood-waste-fired generating plant, incorporating state-of-the-art emission controls, offered a solution to this growing environmental concern and at the same time provided WWP with an energy resource alternative to the hydroelectric supplies of the Northwest.

The Morrison-Knudsen Company designed and constructed the 42.5-MW steam-generating plant on a 19-hectare (46-acre) site at Kettle Falls, Washington. The site selection near the lumber mills took advantage of the plentiful fuel supply while meeting the need for wood waste disposal. A new 115-kV substation was constructed adjacent to the plant to provide transmission access. Construction took 2 1/2 years, and commercial operation began in December 1983.

Cost and Performance

The total capital cost of the plant, exclusive of financing, was about $85.9 million (excluding the substation) or slightly more than $2,000/kW. The estimated levelized capital charge for the plant was 3.22 cents/kWh in 1989. WWP maintains 5- to 10-year contract agreements for wood waste delivery with about 15 large lumber companies within a 161-km (100-mile) radius of the plant, but also signs short-term contracts to take advantage of competitive markets for the wood waste. Given the abundance of the wood waste resource in close proximity to the plant, fuel costs have been very low. In 1989, fuel costs were just $0.75/gigajoule ($0.79/million Btu), or 1.22 cents/kWh, and 85%-90% of that was due to the cost of freight. Including operation and maintenance costs (O&M), total operating costs were 1.43 cents/kWh in 1989, for a total plant generating cost of slightly more than 4.65 cents/kWh.

The Kettle Falls plant has been an operating success, continuously exceeding utility industry operating standards. The plant's availability factor has averaged about 95%. During 1989 and 1990, the station operated 247 consecutive days without an outage. The plant has also consistently operated at a power output of 47 MW, which is 4.5 MW greater than its nameplate rating.

A plant service factor of 75% was originally expected at Kettle Falls--based, in part, on the projected cost of fuel and the availability of alternative power sources (such as inexpensive hydropower). The annual service factor has been as high as 95%, but the plant is usually shut down during the spring runoff, when inexpensive hydropower is readily available.

Environmental Issues

A great emphasis was placed on environmental considerations during the design phase of the project. The plant's boiler produces ash in volume equal to 3% of the fuel. The ash is entrained in the flue gas and is removed in a particulate removal system, which employs an electrostatic precipitator. The recovered ash is then disposed of in a dedicated solid-waste landfill. Recently, the utility received permission to market the ash as a liming agent, to be added to soil to decrease acidity.

The entire particulate removal system was designed to limit particulates to 0.02 grains per standard cubic foot (gr/scf), which is the state standard. The actual emissions rate has been 0.003 gr/scf, well below the state threshold. For its role in cleaning up the air in the Pacific Northwest, WWP was the recipient of Power magazine's Electric Utility Energy Conservation and Environmental Protection Award in 1984.

The Kettle Falls plant uses well water as makeup to the plant's cooling water system. The plant produces only minor amounts of liquid wastes, which are treated on-site prior to discharge.

Success Factors and Barriers

There are several reasons why the Kettle Falls project is a success. First, the plant provided a solution to an existing environmental problem created by the wigwam combustion of forest industry wastes. This helped galvanize initial support for the project. Second, the plant uses local fuels and labor. Third, despite the high initial cost ($2,000/kW), the plant has been cost effective because of its low-cost fuel sources and its above-average plant performance.

At the same time, the project did confront several problems. The higher front-end cost of the plant turned out to be an important issue with state utility regulators. Because the wood plant was a first-of-a-kind endeavor, the total project cost was much higher than that of a conventional power plant of comparable size using fossil fuel. The utility experienced difficulty convincing regulators that the higher cost of the Kettle Falls plant was prudent and justified. Eventually, 10% of the plant cost was disallowed from the rate base.

In addition, fuel supply has recently become an issue for the project. WWP will ship fuel from within a 161-km (100-mile) radius of the plant, but beyond that radius the fuel costs are prohibitive. Although the fuel supply has been plentiful most of the time, the logging reductions in recent years have impacted the supply, increasing fuel costs and reducing the plant service factor.

Regulatory Changes Spur Wood-Fired Plant

Grayling Generating Station
Decker Energy International, Inc.

A power purchase contract clause impeded the Grayling Generating Station's financing for several years until a new law solved the problem. Nine years after it was conceived, the plant began environmentally sound operation with high availability.

Decker Energy International began developing and acquiring energy facilities in 1982. Initially, Decker developed small gas-fired cogeneration projects, but later sought to expand to larger projects. The company viewed wood waste as an unexploited source of fuel. About that time, a remote area of central Michigan faced two growing concerns: first, additional electric capacity was needed by the local utility; and second, the disposal of lumbering refuse was becoming a critical problem. The concept for a wood-waste-fired generating station grew out of these concerns, and Decker soon initiated plans for the 34-MW Grayling Generating Station (GGS).

GGS, located on a 7-hectare (17-acre) site, is owned by the Grayling Generating Station Limited Partnership, which includes Decker Energy, the primary developer; Primary Power, the initial developer; and CMS Generation Company. CMS, a utility subsidiary, manages the project and provides operating services for the partnership. Power is sold to Consumers Power under terms of a negotiated power purchase contract.

Originally conceived of in 1983, the plant took 7 years to develop and 2 years to construct. A consortium of construction companies led by Black & Veatch completed the construction phase of the project on time and within budget. Commercial operation began in June 1992.

Cost and Performance

The plant was constructed under a fixed-price turnkey contract for $50 million, including both engineering and construction. The total project cost, including the cost of financing, was $68 million, or $1,878/kW (nameplate).

The power purchase contract with Consumers Power was originally signed in 1984. Because of project delays and regulatory factors, the contract was renegotiated in 1989. Under the current 35-year contract, Consumers purchases power at a rate of 6.20 cents/kWh consisting of a 4.05 cents/kWh levelized payment for capacity, 0.40 cents/kWh for operation and maintenance, and 1.75 cents/kWh for energy (based on the price of coal).

The plant burns 56 metric tons (55 tons) of wood waste per hour with an output of 36.2 MW. The wastes and by-products from lumbering and milling operations provide 95% of the fuel. An adjacent sawmill serves as the procurement source for the wood fuel. About 50% of the fuel is purchased at a fixed rate while the remaining 50% is procured on a cost-plus basis. The plant design also provides for the future use of 1 kg/s (8000 lb/hr) of steam for a drying kiln at the adjacent sawmill.

To date, the availability factor of 94% has exceeded the guaranteed availability of 88%.

Environmental Issues

The plant employs an electrostatic precipitator for particulate removal and a nitrogen oxide reduction system. The plant also uses a boiler system that minimizes emissions of carbon monoxide. In operation, emissions of these airborne pollutants have remained below the allowed levels.

Approximately two-thirds of the cooling-water needs are supplied by ground wells. The remainder of the water needs are supplied by tertiary wastewater from the town of Grayling. The plant also incorporates a cooling tower to reduce wastewater disposal needs.

After undergoing toxicity tests, the ash from the plant has been designated as benign and thus can be spread on local farmers' fields as fertilizer.

Success Factors and Barriers

The development of the GGS took 9 years from conception to operation. With a power purchase contract in hand, and confident that the GGS was an economically sound project, the developers persisted through years of regulatory delays. The first delay was due to the regulatory out clause in the original power purchase contract, which allowed Consumers to lower the power purchase rate if, at any point, cost recovery was disallowed. This clause discouraged financing for the project because of revenue stream uncertainty. Subsequently, a state law passed in 1987 required utilities to purchase power at a fixed rate for the duration of the project financing.

A second cause of delay was the regulatory approval process. The project approval filing coincided with that of a highly controversial 1300-MW project proposal that dominated regulatory attention. Consequently, the project approval for GGS took 28 months. According to Mike Whiting, chief executive officer of Decker Energy, these types of delays make it very difficult for small power producers to sustain a project's viability.

Community Partnership Leads to Waste-Burning Plant

Bristol Waste-to-Energy Plant
Ogden Martin Systems

Faced with a waste-disposal problem, eight Connecticut communities banded together to build a waste- to-energy plant, which now offers the lowest-cost municipal waste disposal in the state.

In the early 1980s, the Connecticut state legislature passed an act requiring municipalities to provide safe and sanitary disposal of all community-generated solid waste. This legislative act provided the impetus for a consortium of Connecticut communities to plan and develop a waste-to-energy (WTE) facility. A 7.4-hectare (18.2-acre) site in Bristol, adjacent to a sanitary landfill, was chosen for the plant location.

Ogden Martin Systems was selected to perform the design, construction, operation, and maintenance of the facility. Construction began in September 1985, and the plant was dedicated in May 1988. The plant consists of two waterwall furnaces designed to process a minimum of 200,000 metric tons (195,725 tons) of municipal solid waste (MSW) per year. The Bristol Resource Recovery Facility (BRRF) became the first project developed by Ogden Martin involving and serving multiple independent communities. The project, which initially had eight participating communities, now serves 14 communities. The power output is sold to Connecticut Light and Power Company (CL&P).

Cost and Performance

The BRRF is owned and operated by Ogden Martin. A 25-year standard service agreement with the 14 participating communities includes a guaranteed (minimum) waste delivery of 155,750 metric tons (153,300 tons) per year. Each community is committed to delivering all of their waste that is not recycled. Under PURPA, a 25-year, levelized, fixed-rate power purchase contract was negotiated, with CL&P paying the project 8.3 cents/kWh.

The $58.4 million construction cost ($3,583/kW) was financed with $73.5 million in tax exempt revenue bonds and $17.8 million in company equity. Annual O&M costs are approximately $5 million but are more than offset by tipping fees--the charges for accepting the trash. Portions of the tipping revenue are also used to support other waste reduction activities of the communities.

The facility's rated capacity is 16.3 MW. With an availability factor of 92%, the plant has the highest availability of any generating plant on the CL&P grid. Consequently, the relationship between Ogden Martin and the utility has been very good.

Environmental Issues

The Bristol plant was one of the first WTE plants to include both dry-flue-gas scrubbers and fabric-filter baghouses; air emissions are lower than ambient standards by an order of magnitude or more. The plant is also electronically linked to the state environmental compliance office for continuous emissions monitoring.

To date, the ash from the plant has passed all toxicity tests and has been disposed of at the adjacent landfill. However,

a recent change in state regulations now requires that ash and MSW be landfilled separately so their possible toxicity can be monitored. This restriction has cut the life of the original ash disposal site to 4 years from 14-16 years. Now the communities must locate an alternative site for ash disposal.

Success Factors and Barriers

The most important factor contributing to the success of the Bristol project has been the cooperation of the original eight participating communities. Scott Mackin, president and chief operating officer of Ogden Projects (the parent company of Ogden Martin), believes that the development of an effective partnership, where decision making rests with the community participants, is key. For example, because the communities jointly determined the plant site, Ogden Martin avoided siting and zoning delays. Representatives from each community continue to meet to monitor the facility and review legislative issues.

The emphasis on air-emissions control is another factor in the project's success. WTE plants are facing increasing public and environmental scrutiny because of concerns about air emissions. This scrutiny makes it difficult to site WTE plants in many parts of the country.

The efficient design and operation of the Bristol plant also played a role in its success, because they allowed the plant operator to charge a lower tipping fee to the communities involved. The current tipping fee of $50/ton is the lowest in the state; tipping fees at other WTE facilities and landfills range from $55/ton to more than $100/ton. The project's lower tipping fee has attracted a waiting list of potential waste suppliers.

Another factor in the project's success was the availability of a fixed-rate power purchase contract under PURPA. In addition, the facility is located near a utility substation, which minimized transmission and interconnection issues and costs.

Although increased recycling efforts and a depressed New England economy have decreased the waste stream in recent years, this has allowed three additional communities, which have been on a waiting list since the plant's inception, to sign waste delivery contracts with Ogden Martin.

The developers of the Bristol project encountered few permitting or regulatory difficulties, but Richard Ubaldi, vice president of marketing at Ogden Martin, notes that other projects have encountered very time-consuming state regulatory approval processes, which have contributed to higher project costs.

Geothermal

Geothermal resources can be used for power generation or for heating and exist as either dry steam or as hot water. Dry steam, which is a rare resource, can be routed directly to a turbine to generate power. For power generation from hot water, there are two primary conversion technologies: flash plants (for resource temperatures >175 degrees C), which rely on flashing the hot water to steam, and binary plants (for resource temperatures of 100 degrees C to 175 degrees C), which use the heat of the hot water to boil a "working fluid," usually an organic compound. These technologies are currently used to generate electricity from geothermal resources in California, Hawaii, Nevada, and Utah. In 1990, 62 geothermal electric plants were in place with a total generating capacity of slightly more than 2350 MW.

Geothermal energy is also found in the form of geopressured brines. These brines are hot pressurized waters that contain dissolved methane and lie at depths of about 3 km to more than 6 km. The technology has been developed to use this resource, but because it is not currently cost-effective, no commercial power plants have been built.

Geothermal water is sometimes heavily laden with salts and dissolved minerals. In U.S. geothermal developments, the geothermal water is always injected back into the geothermal reservoir, both to replenish the reservoir and to dispose of unwanted dissolved salts. However, geothermal power plants also produce some solid materials, or sludges, that require disposal in approved sites.

Although geothermal power generation requires relatively high-temperature resources that exist primarily in the West,

low-temperature resources (<130 degrees C) are more widespread across the country. These resources can be used for direct-use applications such as heat pumps, district heating, space heating and cooling, aquaculture, industrial processes, and domestic hot water. It is estimated that there are 130,000 direct-use installations with a total thermal installed capacity of 2100 MW and an annual energy use of 19.8 petajoules (18.8 trillion Btu). The fastest growing direct-use application is geothermal (ground source) heat pumps.

Geothermal Loan Encourages New Power Industry

Ormesa Geothermal Complex
Ormesa Power Corporation (Ormat Group)

A guaranteed loan from the U.S. Department of Energy was crucial in overcoming financial uncertainty when developing the Ormesa geothermal plants. The modular facility has since achieved a 98% on-line availability, and the loan has been refinanced privately.

In 1986, the Ormat Group acquired geothermal leaseholds, along with preexisting utility power purchase contracts, from Republic Geothermal Company. These acquisitions established the beginning of the Ormesa Geothermal Complex, which is now operated by OESI Power Corporation.

Located on a 23.3-square-km (9-square-mile) development in the Imperial Valley near Holtville, California, the Ormesa Complex was developed over a period of 4 years, from 1986-1989. The modularity of the Ormat technology allowed power plant segments to be added as new production wells were drilled and proven, rather than requiring many wells to be drilled before building one large plant. Each of the four plants, ranging in size from 6.5 MW to 24.0 MW, and totaling 57 MW, was added incrementally as new wells were drilled. Each power plant module is self-contained; should one module need to be serviced, the remaining units can continue to generate power.

A 150 degree C geothermal resource is tapped by a network of 18 pumped production wells and 15 injection wells to serve the four binary plants. The complex is interconnected with the Imperial Irrigation District (IID) transmission system, and the power is wheeled and sold to the Southern California Edison Company (SCE) under a power purchase contract.

Cost and Performance

The average capital cost of the Ormesa units was $2,500/kW, including development of the well fields, associated support infrastructure, and the geothermal power plant modules. Approximately 75% of this cost was for the power plant with the remainder for the field development. With resource acquisition, financing and transaction costs, and capital reserve funds, the installed project cost averaged $3,500/kW. Operation and maintenance costs for the plant and the field are 0.9 cents/kWh.

The Ormesa Complex has had an on-line availability of 98%, which is attributed to the redundancies present in the modular technology.

Environmental Issues

The operation of binary system geothermal plants has limited airborne environmental impact because the geothermal water is not released to the environment. However, some gases (such as carbon dioxide) are released from the water and vented as its pressure drops. The most important environmental concerns involve siting, water use for cooling, and sludge disposal, although the latter has not been a significant factor because of the minimal amounts of sludge produced.

The disturbance of wildlife habitats was the most significant siting issue at Ormesa. During the construction of the project, it was necessary to reroute several roads and construct berms to protect lizard habitats.

Success Factors and Barriers

The most significant factor contributing to the success of the Ormesa geothermal complex was the availability of a loan guarantee from the U.S. Department of Energy. The guarantee, which was available to developers from 1974-1984 under the Geothermal Loan Guarantee Program, was invaluable in obtaining the original financing for the project. Because binary geothermal technology was unproven at the time, lenders were reluctant to make a financial commitment to the project. The loan guarantee provided the necessary security to overcome this initial reluctance. The modularity of the technology also helped address lender reservations over plant availability and longevity.

Approximately 1 year after the loan guarantee became effective, the first unit (Ormesa I) was refinanced with long-term debt through private sources. All subsequent units were privately financed because institutional lenders had become more comfortable with the technology. The power purchase contracts with SCE also provided a guaranteed revenue stream. Another significant factor in the project's success was the company's assumption of total responsibility for project development (including engineering, construction, project management, and start-up services), which helped avoid project delays and costly overruns.

Initially, the transmission of power to SCE presented a problem because existing transmission lines out of the development area could not accommodate the additional power generation. In 1986, the geothermal developers in the Imperial Valley formed a funding group to provide IID with a loan to construct a new transmission line to the SCE interconnection. The resulting 185-km (115-mile), 230-kV transmission line is owned by IID. Because IID is a publicly owned utility, transmission line approval was not required from state utility regulators.

OESI Power Corp. believes there are several important lessons in the Ormesa development experience: it proves the feasibility of large-scale power generation from lower-temperature hydrothermal resources; it proves the viability of incremental resource development; and it provides a successful example of federal government aid to a nascent energy industry.

Project Consolidation Rescues Geothermal Development

Dixie Valley Project
Oxbow Geothermal (Oxbow Corporation)

Combining several small geothermal projects allowed Oxbow Geothermal to achieve the economies necessary to construct its own transmission line. Although construction approvals were difficult to obtain, existing power purchase contracts gave the company the impetus to overcome those obstacles.

In 1985, Oxbow Geothermal, a unit of Oxbow Corp., acquired three separate geothermal leaseholds in the Dixie Valley area of Nevada from Sun Company and Trans-Pacific Geothermal. Both Sun and Trans-Pacific held power purchase contracts with the Southern California Edison Company (SCE) for power sales from proposed geothermal plants of 10-20 MW each, but could not economically justify development of these smaller projects because of transmission costs. Oxbow developed a plan to combine the smaller developments into one 55-MW geothermal power facility, making it economically feasible to construct a 354-km (220-mile), 230-kV transmission line to interconnect with SCE. The resulting line is the largest privately owned electric transmission facility in the country.

The turnkey contractor for the generation plant was Ebasco Services, which selected the Ben Holt Company as the project engineer. The project took 3 1/2 years from the acquisition of the geothermal leaseholds to plant completion. The single-unit, double-flash plant, brought on-line in July 1988, was the largest of its kind in the country.

Cost and Performance

The capital cost of the power project, including acquisition and drilling costs, was $135 million ($2,455/kW). The transmission line added $35 million. The entire project was financed with $70 million in company equity and $100 million in non-recourse bank loans. In March 1989, the project was refinanced with a $170 million non-recourse project finance loan from Prudential Power Funding, Inc. The plant has had an availability factor of approximately 99% and has continually met contract power output requirements.

Although the project was eligible for the federal 10% energy tax credit, this credit had a fairly modest impact on the

project's economics because of alternative minimum tax considerations.

Environmental Issues

Because the geothermal field is located in an unpopulated desert area, there was no opposition to the siting of the facility. However, the siting of the transmission line did encounter some delay in addressing concerns over wildlife areas and other protected areas.

The geothermal water in the Dixie Valley resource is unusually clean; therefore, disposal of waste sludge and water has not been a significant issue. Furthermore, the operators reinject as much of the water as possible to maintain pressure in the wells. With approximately 75% of the water reinjected and 23% lost to evaporation, only a small percentage (2%) requires disposal and is discharged into a nearby salt marsh.

Success Factors and Barriers

The most significant success factor for the Dixie Valley project was the pre-existing utility power purchase contracts. Having a power purchase agreement in hand eliminated some of the risk in financing the first-of-its-size geothermal power plant. Another success factor was the acquisition of geothermal leaseholds where extensive exploration had already been performed to confirm the resource. This helped minimize the total project development time.

Probably the most difficult hurdle that Oxbow encountered was the transmission line approval. Negotiations with the U.S. Bureau of Land Management (BLM) and other landowners for transmission right of ways were time consuming, taking almost 2 years. Although BLM and the other landowners were cooperative, the route of the line had to be changed several times to bypass wildlife and protected areas, leading to additional expense. Oxbow maintains that without the cooperation of the BLM and the various counties and private landowners along the way, power transmission, and thus the entire project development, would not have been possible. Barney Rush, executive vice president of Oxbow, stresses that the maintenance of a positive relationship with both BLM and SCE has been an important factor in the continuing success of the project.

Hydropower

Hydropower accounts for almost one-half of the total energy contribution from renewable energy sources in the United States. Hydropower uses the energy of flowing water to turn a turbine, which rotates a generator to produce electricity. Although many hydropower facilities use large impoundment dams, hydropower can also be generated by diverting a portion of a stream or river. Such diversion projects may require a dam, but the dams are usually much smaller and less obtrusive than impoundment dams.

Hydropower technology can also be used to store energy. During low-load periods, excess electrical supplies can be routed to a pumped storage facility, which stores the energy by pumping water from a lower reservoir to another reservoir at a higher elevation. During peak-load periods, the water is allowed to return from the upper reservoir to the lower reservoir, turning a turbine and generating electricity in the process.

Hydropower plants have a rich history and played a major role in spurring industrial development in the 19th century. By the 1930s, hydropower provided 30% of the nation's generating capacity. However, the growth of other non-renewable generation sources slowly eroded the hydropower capacity share to its current 12%.

Considerable potential still exists for obtaining additional capacity from hydropower resources. The Federal Energy Regulatory Commission (FERC) estimates that the nation's existing hydropower capacity of more than 72,000 MW could be nearly doubled through a combination of new site development, development of generating capability at preexisting impoundments, and equipment upgrade at existing plants. There is also a significant potential for development of small hydropower facilities throughout the country.

Nevertheless, hydropower development has slowed in recent years because of environmental concerns and more stringent regulatory and operating requirements. As a result of the Electric Consumers Protection Act (ECPA), enacted in 1986, the time and cost of licensing hydroelectric projects has escalated. Many older hydropower projects will

require relicensing during the 1990s, exposing these projects to greater scrutiny and a potential loss of capacity.

Run-of-River Plant Minimizes Environmental Impacts

Sidney A. Murray Hydroelectric Station
Catalyst Energy Corporation

A combination of innovative design and construction features helped Vidalia, Louisiana, achieve an environmentally benign solution to its power problems.

In 1977, the town of Vidalia, Louisiana, was faced with significant electric power rate increases due to cost recovery on two nuclear power plants by the local utility, Louisiana Power & Light (LP&L). Sidney A. Murray, the mayor of Vidalia, engaged community support in the search for a less costly source of power.

The Baton Rouge engineering firm of Forte and Tablada Inc. was hired to investigate alternate sources of power that would stabilize or reduce the town's electric power rates. A potential hydropower site was identified approximately 64 km (40 miles) south of Vidalia on the Mississippi river. Initially, development of the site conflicted with the responsibilities of the U.S. Army Corps of Engineers to maintain unimpeded navigation. A second site was eventually identified upstream from the first.

The facility was designed as run-of-the-river; that is, the project was to take advantage of the existing elevation drop along the river and rely on the natural river flow, thus avoiding the need for a large impoundment dam. A "bulb" turbine engineering design was used to accommodate both the low head (low elevation drop between the inlet and the outlet) and the limitations that were required to maintain unimpeded navigation. Because of construction site constraints caused by the remoteness of the project and the lack of qualified labor, much of the 192-MW plant was prefabricated in a New Orleans shipyard and floated 451 km (280 miles) up river. The plant began full-scale operation in 1990.

Cost and Performance

A total of $550 million was raised for project development under a limited partnership--$410 million ($2,135/kW) for the construction, design, engineering, land, and 64 km (40 miles) of transmission, and the balance for interest. Catalyst Vidalia Corp., a subsidiary of Catalyst Energy, served as the general partner with Dominion Capital Inc., an affiliate of Virginia Power, as a limited partner. The project received exemptions from sales and use taxes under the State Enterprise Zone Program and was granted a 10-year exemption from ad valorem taxes on buildings and equipment.

Under an approved 42-year power purchase contract with LP&L, the power purchase rate is 6.5 cents/kWh with a fixed escalation schedule. The town of Vidalia currently purchases 6% of the power at a price of 6.0 cents/kWh and has an option to eventually purchase up to 15% of the power generated.

With a capacity factor of approximately 55%, the plant operates more continuously than many run-of-the-river hydro plants. The greater output is attributed to the special engineering design for low-head waters. Although warranty activities are continuing, the plant availability is estimated to be in excess of 99%.

Environmental Issues

Environmental impact assessments specific to the Vidalia project were not required due to extensive studies on river flow and environmental impacts that had already been conducted by the Army Corps of Engineers. According to Sidney Murray, "the only impact environmentally is that the town of Vidalia now has a good, clean, safe, odorless power plant which supplies all its power." Designing the plant in accordance with the Corps' preexisting water management objectives minimized additional impacts on the environment.

Success Factors and Barriers

Securing financing for the Vidalia project proved difficult until several well-capitalized institutional finance companies

became involved. The existence of a power purchase contract, with its unusually long contract period of 42 years, helped reduce financial risk.

A second factor contributing to the success of the project was the relatively quick issuance of a construction license by the Federal Energy Regulatory Commission (FERC). Because much of the data collection and site analyses had already been undertaken by the Corps, many of the federal regulatory requirements had been addressed. As a result, after the design and site parameters had been identified, a construction license was issued within 10 months.

Other factors contributing to the success of the Vidalia project included a strong commitment to the development by all parties involved and the sharing of the Corps' river flow studies, which saved a great deal of preliminary effort on the part of the project developers. The off-site prefabrication of the plant allowed site work to be performed simultaneously with the construction of the facility. This last factor resulted in an estimated $125 million savings in carrying costs.

However, the project was not without problems. Delays were experienced while several regulatory issues were resolved. First, the original license had to be amended to accommodate the limited partnership; for the owners to receive tax credits, the town could not be part of the partnership. Because of a preference to license municipalities, FERC originally denied the transfer of the license from the city of Vidalia to the limited partnership, causing a 2-year delay while partnership agreements were amended to satisfy FERC requirements.

Second, because the project exceeded the PURPA 80-MW threshold, it became subject to the Public Utility Holding Company Act (PUHCA). As a result, the power purchase contract had to be approved by FERC and the entire transaction was subject to review by the Securities and Exchange Commission (SEC). Eventually, the parties managed to obtain a project exemption from both the SEC and PUHCA, but these requirements caused additional delays. These issues have since been lessened by the PUHCA reforms contained in the Energy Policy Act of 1992.

Photovoltaics

Photovoltaics (PV) energy technology employs a solid-state device to directly convert sunlight into electricity. PV cells, also called solar cells, represent one of the most benign forms of electricity generation available, because they can be used to make stand-alone systems with no fuel or cooling requirements and no operating emissions or noise. However, because much of the current PV cell technology uses crystalline semiconductor materials (similar to integrated circuit chips), production costs have been high. Even so, technology improvements have reduced PV generation costs from $1.50/kWh in 1980 to a range of $0.30-$0.40/kWh today.

PV cells are combined into large panels, or modules, which are used commercially in a number of remote and stand-alone applications. Worldwide sales of PV modules have doubled in the last 5 years and, in 1992, totaled about 60 MW. However, the largest and most lucrative market, utility bulk power generation, remains elusive because of the high cost of PV systems.

Several collaborative programs have been initiated recently between the federal government (through the U.S. Department of Energy) and the PV manufacturing industry to develop lower cost PV manufacturing processes. In addition, the electric utility industry has joined with these same entities to identify current, cost-effective, utility markets for PV systems, thus providing a near-term market pathway for further PV cost reductions. For example, Idaho Power Company now has a pilot program to supply selected customers with PV systems for remote applications, including remote residences and vacation homes, stock watering wells, sign lighting systems, communication relays, and cathodic protection systems. Delamarva Power and Light--serving Delaware, Maryland, and Virginia--and the Sacramento Municipal Utility District are also installing PV systems as a form of demand management.

Stand-Alone PV Systems Meet Many Utility Needs

Helms Pumped Storage Plant and Other PV Applications
Pacific Gas and Electric Company

A total of about 1100 PV systems are providing a peak capacity of 44 kW for 17 different cost- effective applications

throughout the Pacific Gas and Electric Company's service area.

In 1989, the research and development department at the Pacific Gas and Electric Company (PG&E) in San Ramon, California, began a survey of the utility's applications that used photovoltaic (PV) systems. The department found that hundreds of PV systems were already in use by the utility company. Several PG&E departments had independently determined that PV represented the most cost-effective option for meeting small-scale, remote power needs. By December 1992, about 1100 cost-effective PV systems had been installed by the company. The total peak capacity of these PV systems is 44 kW.

Although PG&E has found approximately 17 different applications, the majority of the PV systems provide power for gas flow computers, automated gas meters, and water level sensors. Two distributed PV applications that have proven to be particularly reliable are a power system for a gatehouse at a pumped storage plant and power systems for cathodic protection of natural gas lines.

One of the gatehouses at the Helms pumped storage plant near Courtright Dam used thermoelectric generators (TEGs) to charge a 500-amp-hour battery bank that powers lights, a radio transmitter, surface detection equipment, and relays to start emergency penstock gate closure. The TEGs required substantial operation and maintenance as well as propane fuel. Analysis suggested that maintaining the TEGs at the remote location was neither cost efficient nor reliable. As a result, the TEGs were replaced with a 5.8-kW PV system.

PG&E has also installed stand-alone PV systems for cathodic protection of two 40-km (25-mile) sections of natural gas lines near the town of Topock, in the California desert. The PV systems were chosen based on economic considerations and because they provided a solution to right-of-way issues for power line extension. The first system uses a 7-kW, fixed PV array to charge a 120-V lead-acid battery bank that maintains a constant current of 6 amps. The second system uses a 1-kW single-axis passive-tracking array to charge a 24-V lead-acid battery that maintains a constant current of 2 amps.

Cost and Performance

The cost of the PG&E PV systems vary by project. Although cost information is not available from the utility, capital costs for a typical off-grid PV system may range from $10,000 to $20,000/kW installed. However, PV systems are often the most cost-effective solution because of their reliability, modularity, low maintenance, and independence from transmission and distribution systems.

Financing for the PV systems typically comes from standard operating budgets for each line organization. The overall reliability of the systems has been high and has led to widespread acceptance within the company of the capability of PV systems to serve small off-grid loads. PV systems are even used on transmission towers to accommodate small loads that would otherwise require a transformer.

Environmental Issues

Currently, the largest environmental concern related to PV systems is their visual impact. However, that has not been an issue in the PG&E projects, because most of the utility's PV systems are small-scale and remotely located. PG&E believes that PV installations would have to increase many fold before their visual impact became a siting issue.

Success Factors and Barriers

The primary factor contributing to the successful installation of PV systems in the PG&E service territory is the cost effectiveness of the systems. While PV is not currently cost competitive as a bulk power source, PV does offer the utility an economic and reliable source to serve small-scale, stand-alone power needs.

Although PG&E found many applications for PV systems within its service area, other utilities have installed relatively few PV systems. The main barrier to the greater use of PV systems is a lack of awareness within utilities as to the advantages of PV systems in certain applications.

Utility Demonstrates Feasibility of Rooftop PV Systems

Gardner PV Project
New England Electric System

A demonstration project in Gardner, Massachusetts, showed that rooftop PV systems could be interconnected with the utility grid without adverse effects. The systems provide load management without encountering siting issues.

A commitment to finding alternate electric energy sources, in part, spurred New England Electric System (NEES) to begin an investigation into PV technology in the mid-1980s. NEES was also concerned that if PV costs were to become competitive with bulk power generation in the future, there would be an increase in customer-owned PV systems. NEES sought to examine the possible impact that thousands of small generating units would have on its power distribution system.

As part of a 10-year Commercial and Residential Photovoltaic Systems Research and Demonstration Project, a PV panel was installed on each of 30 houses in Gardner, Massachusetts. Each house had a southern exposure and was located on one of two neighboring streets served by a single distribution feeder. The project was monitored by New England Power Service Company (NEPSCo), a subsidiary of NEES.

Construction of the project began in 1985 and took about 2 years to complete. The multiple objectives of the PV project were to gather data on the reliability of the system components, record the variation in system power output during the year, study the effects that a cluster of PV installations has on a single distribution line, and showcase PV system components made in Massachusetts.

Cost and Performance

Each PV system has a rated output of 2 kW and generates about 2200 kWh/yr. At a cost of $20,000 per system, the generation cost is $0.91/kWh, assuming a 10% discount rate. Although these costs are very high by conventional standards, the intended purpose of the project was to demonstrate the technology and study distribution system impacts, knowing that PV costs will fall in the future.

The costs of the Gardner project were paid through NEPSCo's research and development budget with no attempt at cost recovery. The Electric Power Research Institute (EPRI) contributed funds to the monitoring effort. Ownership of the PV systems will be transferred to each participating homeowner upon completion of the research phase of the project.

Energy production, monitored from 1988 through 1992, varied from approximately 50 kWh in winter months to 270 kWh in summer months. Much of the energy produced by the PV systems in the summer months occurred during the utility's peak hours, providing a load management benefit.

The results of the 3-year, EPRI-funded study indicated that the PV systems produced no adverse effects on the operation, protection, and control of the utility distribution system. There were no problems with the operation of the systems and the project proved that residential PV systems can be readily installed by local roofers and electricians.

Environmental Issues

Customers had no complaints about environmental issues such as the visual impact of the panels. Project participants appreciated both the free electricity and the lack of emissions from the energy source.

Success Factors and Barriers

According to Dr. John J. Bzura, principal engineer for the Gardner project, the most important factor contributing to the project's technical success was "using the highest quality equipment available and choosing the most experienced, qualified people to design and install the systems." Because of the R&D nature of the project, and the fact that NEPSCo did not seek cost recovery, there was no regulatory involvement.

Also, by locating the project in Gardner, Massachusetts, an economically depressed area at the time, and utilizing local labor and manufacturers, the local economy was boosted. Community support for the project, therefore, was high. The detailed studies that have resulted from this project have promoted the utility's reputation regarding PV systems and have increased the awareness of PV potential in New England.

Other utilities have recently undertaken similar research activities in rooftop PV installations. For example, the Southern California Edison Company (SCE), in conjunction with Texas Instruments Inc., is investigating a prototype low-cost rooftop PV module. According to Nick Patapoff, SCE project manager, the value of this research is in the potential for the utility to provide peaking power to residents without overloading transmission lines. "The home run ball (with PV) is on rooftop capabilities," says Patapoff.

Solar Thermal

Solar thermal systems collect the thermal energy in solar radiation for direct use in low- to high-temperature thermal applications. High-temperature applications include the generation of electricity using conventional steam cycle technology. For electricity generation, several types of collection systems (parabolic trough, central receiver, and parabolic dish) may be used to concentrate and convert the solar resource. Higher temperatures result in greater thermodynamic energy conversion efficiencies. Solar thermal technology offers significant potential for meeting utility peaking or intermediate electric power generation needs in sunny climates.

The leading solar thermal electric technology is the parabolic trough, which focuses the sunlight on a tube that carries a heat-absorbing fluid, usually oil. The fluid is circulated through a boiler, where its heat is used to boil water to steam, and the steam is routed to a turbine to generate electricity. More than 350 MW of parabolic-trough electric generating capacity is operating in California's Mojave Desert, connected to the Southern California Edison Company (SCE) utility grid. These projects, profiled on the following pages, represent more than 95% of the world's solar electric capacity.

Central-receiver technology is about to be rejuvenated in the United States. Central-receiver plants use a field of mirrors to focus the sun's energy on a central receiver, which is mounted on a tower. An experimental 10-MW central-receiver power plant, Solar One, was built and operated in Barstow, California, during the 1980s by a government-industry team. Plans are currently under way to refurbish this plant with an improved conversion technology. The new plant will be named Solar Two, and is being developed by a consortium of several utilities, private companies, California government agencies, and the U.S. Department of Energy.

Parabolic dishes are relatively small-scale applications of solar thermal electric technology. A parabolic dish tracks the sun and focuses its heat on a Stirling engine, which converts the heat energy to mechanical energy. The mechanical energy drives a turbine to generate power. Parabolic dish systems can generate 5-25 kW of power; they are expected to find applications in remote locations, and the larger units might eventually be grid-connected to provide voltage support.

Low-temperature solar thermal applications include domestic water and space heating for residential and commercial buildings, as well as building designs and orientations that take full advantage of the sun's light and heat. Tax credits available during the late 1970s and early 1980s led to thousands of solar heating system installations across the United States. However, installations waned after the tax credits expired in the mid-1980s. Several utilities are again initiating programs to utilize solar water heating systems as a demand-side management measure.

Solar Thermal Plants Meet Utility Peaking Needs

Luz Solar Electric Generating Systems
Luz International, Ltd.

Since 1984, Luz International, Ltd. had been building successively better solar electric power plants in California's Mojave desert. But the tax credit that helped the company succeed also contributed to its ultimate failure.

In 1984, Luz International, Ltd. built its first Solar Electric Generating System (SEGS) plant and became the world

leader in solar power generation. The SEGS technology consists of modular parabolic-trough solar collector systems, which use oil as a heat transfer medium. One unique aspect of the Luz technology is the use of a natural-gas-fired boiler or oil heater to supplement the thermal energy from the solar field or to operate the plant independently during evening hours. The use of natural gas is limited to 25% of total energy input under FERC rules implementing PURPA.

Nine separate SEGS plants have been constructed by Luz at three different sites in California's Mojave Desert. SEGS I is a 13.8-MW plant with 3 hours of dedicated thermal storage and a natural gas superheater. SEGS II, built in 1985, is a 30-MW plant and was the first of the SEGS plants to incorporate a natural gas-fired backup boiler.

Five additional 30-MW plants (SEGS III-VII), incorporating an advanced collector design and other improvements, were constructed from 1986 to 1988, with the 30-MW size dictated by PURPA limitations. As Luz built new plants, the company spent more than $22 million to improve the SEGS technology. With SEGS VIII and IX, Luz incorporated a third-generation collector design with other improvements, and achieved additional economies of scale by moving to an 80-MW plant design when the PURPA size limitation was temporarily raised.

In 1991, Luz ran into financial trouble, a casualty of reduced profit margins resulting from a number of factors, including lower fossil fuel prices, which reduced utility avoided costs, and uncertainty regarding the federal tax credit. Luz eventually filed for Chapter 7 bankruptcy, and the operation of its existing plants was taken over by the investor groups.

Cost and Performance

SEGS I was installed at a total cost of $62 million (~$4,500/kW) and generates power at 24 cents/kWh (in 1988 real levelized dollars). The improvements incorporated into the SEGS III-VI plants (~$3,400/kW) reduced generation costs to about 12 cents/kWh, and the third-generation technology, embodied in the 80-MW design at an installed cost of $2,875/kW, reduced power costs still further, to 8-10 cents/kWh. All of the Luz plants operate under power purchase contracts with SCE, but the two 80-MW plants are operated under less lucrative contracts that allow payments to vary with SCE's avoided energy costs.

In addition to the direct plant costs, Luz incurred costs related to grid interconnection and power transmission. Although the first two project sites were located in close proximity to existing substations with adequate capacity, the third site required that Luz construct a 19.3-km (12-mile), 220-kV transmission line.

The Luz plants are operated to maximize the power contribution during SCE's peak-load period, because that is the time of highest utility payments. The plants operate for almost 100% of the on-peak hours, 80% of the summer mid-peak hours, and 66% of the winter mid-peak hours. On average, only 13% of the total SEGS generation occurs during off-peak hours. The SEGS III-VII plants have met performance expectations within 10%, while SEGS VIII and SEGS IX experienced initial problems caused by a new gas-fired oil heater design.

Environmental Issues

The SEGS plants help reduce environmental emissions. Although 25% of the SEGS generation is based on natural gas, the plants still produce only one-fourth of the emissions from a comparably-sized fossil fuel plant.

Because solar energy is a diffuse resource, the dedicated land requirement for the Luz plants is large compared to conventional plants--on the order of 2 hectares/MW (5 acres/MW). However, when the full-fuel-cycle land requirements (including mining and waste disposal) of other energy resources are taken into account, Luz plants use no more land than conventional plants.

Cooling water requirements can also be an issue in arid areas, but have not been a problem for the SEGS plants. SEGS I, II, VIII, and IX all draw sufficient cooling water from underground aquifers. SEGS III-VII buy aqueduct water from the local water district. Although the water quality deteriorated during the recent California drought, the plant capacity was never limited because of a lack of cooling water. Dry cooling is an option that would reduce water use by about 80% at a modest increase in plant cost.

Finally, the use of oil as a thermal transfer medium can create a potential hazard. In early 1990, the SEGS VIII plant experienced a series of explosions when a fire started in one of the four gas-fired oil heaters. The fire was caused by a design flaw that has since been corrected.

Success Factors and Barriers

Over its life, Luz raised more than one billion dollars for the SEGS projects. Luz's success during the 1980s was largely because of the availability of federal and state tax credits, the enactment of PURPA, the development of California's standard-offer contracts, and the persistence of the company. However, as short-run utility avoided costs fell in the late-1980s, it became more difficult to finance new SEGS plants, and the technology cost improvements could not keep up with falling natural gas prices.

At the same time, the federal policies that had provided a favorable market environment for Luz in the early and mid-1980s contributed to its financial collapse in 1991. Beginning in 1986, the 10% energy tax credit for solar energy property was extended in a piecemeal fashion, anywhere from 9 months to 2 years at a time, creating tremendous financing uncertainty. In 1990, Luz had to build SEGS IX in just 7 months to qualify for the tax credit. This led to serious cost overruns that exceeded revenue coverage, resulting in a loss of project profitability. Furthermore, the tax credit could not be applied against the alternative minimum tax established in the 1986 Tax Reform Act. The 10% solar tax credit was permanently extended in the Energy Policy Act of 1992, but this came too late to benefit Luz.

PURPA's QF size limitation also prevented the SEGS technology from achieving the optimal size for economies of scale, which is believed to be 150-200 MW. Although the PURPA size limitation was eventually lifted, this change again came too late for Luz.

Finally, although electric utility subsidiaries contributed nearly 50% of the total project equity, utility companies were not eligible for many of the incentives available to non-utility developers. The lack of incentives for utility investments in solar power was an important barrier to greater interest and direct participation by utilities in SEGS projects.

Wind

Wind turbines capture the wind's energy with a rotor, usually consisting of two or three blades mounted on a shaft; the spinning blade shaft rotates a generator to produce electricity. The turbines are mounted on towers to maximize the capture of wind energy, because the wind is generally slower and more turbulent close to the ground. There are two types of wind turbine designs: the vertical-axis wind turbine, which resembles an upright eggbeater, and the horizontal-axis wind turbine, which resembles a windmill. Although wind turbines can be stand-alone systems, there are operating advantages to siting wind turbines in a large array to form a windplant.

Important progress has been made in the development of wind energy technology. Currently, there are more than 1500 MW of wind-generating capacity in operation in California. Improved turbine designs and operation have contributed to a reduction in wind energy generation costs from 25 cents/kWh in 1980 to a range of 7-9 cents/kWh for today's commercially installed machines in the most favorable locations. Turbine availabilities of 95% or above are now the norm, and operation and maintenance (O&M) costs have declined sharply from 4 cents/kWh to 1-2 cents/kWh today.

Continued research and commercial demonstration of a new class of wind turbines with advanced airfoils and electronics, and some incorporating variable speed operation, are expected to further reduce the cost of wind energy to 5 cents/kWh or less in regions with more moderate winds. These technological developments have caught the interest of a number of electric utilities outside of California that are now exploring wind energy development.

Performance Improvements Make Wind Power Economical

Altamont Pass Windplants
U.S. Windpower, Inc.

Since 1981, U.S. Windpower,Inc. has continually improved the performance of its wind turbines, reducing the cost of electricity by almost half. The company's newest turbine is expected to produce electricity at a cost of 5 cents/kWh or

less.

Founded in 1974, U.S. Windpower, Inc. (USW), a subsidiary of the privately held Kenetech Corp., is the world's oldest and largest wind energy company. USW currently operates 23 windplants, utilizing its Model 56-100, a 100-kW horizontal-axis turbine first installed in 1983. These windplants range in size from 25 MW to 85 MW. The turbines are manufactured at the company's headquarters in Livermore, California, and then erected on the windplant site, with a field construction time of about 6 months. The performance of each turbine is monitored from a central control room. The majority of USW's windplants are located in the Altamont Pass, east of San Francisco, and the power is sold to the Pacific Gas and Electric Company.

With utility industry support, USW has developed a larger, 360-kW horizontal-axis turbine, the 33M-VS, which utilizes variable speed drive and advanced power electronics to reduce component stresses and increase energy capture. The company erected the first prototype in 1989 and began commercial production in 1993. USW President Dale Osborn has stated that "this new, large, utility-scale wind turbine is the key element of our business strategy for the future. If we can achieve the technical and financial goals for this project, we will define a completely new market for wind power--a market in which it will be commercially viable generation on the basis of fuel savings alone."

Cost and Performance

The current capital cost for the Model 56-100 turbine is about $1,200/kW, and power generation costs are about 7-9 cents/kWh in regions with favorable winds. In contrast, the first USW turbines, erected in 1981, generated power at a cost of more than 12 cents/kWh. Most of this cost reduction has been attributed to performance improvements, such as higher turbine availabilities and capacity factors, rather than lower turbine costs. Wind turbine availabilities are now in the 95%-99% range, with capacity factors of 20%-25% in California. Capacity factors are expected to reach as high as 40% in parts of the Midwest and Northeast, which have more moderate but also more constant winds.

The capital cost for the advanced 33M-VS turbine is estimated to be $800/kW in large-scale production with an O&M cost of 1.2 cents/kWh. Both USW and the Electric Power Research Institute estimate that the levelized cost of electricity from the 33M-VS will be 5 cents/kWh or less.

Environmental Issues

The three notable environmental impacts of windplants are aesthetics, noise, and avian mortality. The avian mortality issue has been most pronounced in the Altamont Pass area because of a large raptor (eagles and hawks) population. Other California wind development areas (such as Tehachapi Pass and Palm Springs) have not experienced avian-related problems. To address avian mortality, USW has established a task force of leading U.S. ornithologists and biologists to study avian behavior in the Altamont Pass and suggest mitigation measures. The company has also taken remedial measures such as painting turbine blades and installing sonar systems.

Although turbine noise can be an issue, its potential impact is reduced if turbines are sited away from populated areas. Where in close proximity to residences, USW ensures that its windplants meet local noise ordinances.

Typically, USW works closely with the community on siting and environmental issues. Aesthetic (visual) concerns are studied initially through visual analyses in which, through an electronic process, turbines are visually located on a landscape of the proposed site, providing a simulated picture of the complete project.

Finally, because wind turbines occupy less than 10% of the land area at windplant sites, the sites allow for multiple land use. At Altamont Pass, traditional land uses, such as livestock grazing, can still be accommodated. In fact, landowners often earn more from their wind leases than from the traditional land uses.

Success Factors and Barriers

According to Eric Miller, director of business development at USW, the most important factor contributing to the success of the USW projects has been the existence of utility power purchase contracts. Miller notes that these contracts "practically invented the industry."

Several additional external factors contributed to the USW success, including the federal and state tax incentives of the early 1980s and support of the state regulatory commission with regard to the utility power purchase contracts. In addition, a need for power existed in the state, state energy policy is supportive of renewable energy development, and the power generated by the wind projects is supplied to large utilities with power systems that can easily accommodate the intermittent wind system power output. To date, transmission has not been an issue for USW projects because these projects have been located close to existing transmission facilities.

Windplant development involves a time consuming and expensive review process, primarily at the county level. To ensure the continued success of wind power development, Miller believes there needs to be greater consideration of the relative environmental merits of power generation sources. If environmental attributes are considered, wind projects may become the least-cost option for utilities seeking to expand capacity. Says Miller, "if the total costs to society are included in the comparison of wind energy to fossil fuels, then no special treatment is needed for wind projects. They sell themselves."

For More Information

The U.S. Department of Energy (DOE) conducts research on all the renewable energy technologies described in this document. For further information about DOE research programs, contact:

Deputy Assistant Secretary, Office of Utility Technologies
U.S. Department of Energy
EE-10

Director, Office of Renewable Energy Conversion
U.S. Department of Energy
EE-12

Director, Office of Solar Energy Conversion
U.S. Department of Energy
EE-13

Director, Office of Energy Management
U.S. Department of Energy
EE-14

U.S. Department of Energy
Forrestal Building
1000 Independence Ave., SW
Washington, DC 20585

Produced by the
National Renewable Energy Laboratory
1617 Cole Boulevard
Golden, CO 80401-3393

The National Renewable Energy Laboratory is a national laboratory of the U.S. Department of Energy and is operated by the Midwest Research Institute.

The hardcopy version of this is designated as: DOE/CH10093-206, DE93000081, October 1993.

The hardcopy version is printed in the United States of America with renewable source ink on paper containing at least 50% wastepaper, including 10% postconsumer waste.

NOTICE

Hardcopy available to DOE and DOE contractors from:
Office of Scientific and Technical Information (OSTI)
P.O. Box 62
Oak Ridge, TN 37831
Prices available by calling (615) 576-8401

Hardcopy also available from:
National Technical Information Service
U.S. Department of Commerce
5285 Port Royal Road
Springfield, VA 22161
(703) 487-4650

Information pertaining to the pricing codes can be found in the current issue of the following publications which are generally available in most libraries: Government Reports Announcements and Index (GRA and I); Scientific and Technical Abstract Reports (STAR); and publication NTIS-PR-360 available from NTIS at the above address.

Last Modified: 03/00/2000